

**HYDRAULIC STIMULATION OF NATURAL FRACTURES AS REVEALED BY
INDUCED MICROEARTHQUAKES,
CARTHAGE COTTON VALLEY GAS FIELD, EAST TEXAS**

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ABSTRACT

We have produced a high-resolution microseismic image of a hydraulic fracture stimulation in the Carthage Cotton Valley gas field of east Texas. Gas is produced from multiple, low-permeability sands within an interbedded sand-shale sequence. We improved the precision of microseismic event locations 4-fold over initial locations by manually repicking the waveforms in a spatial sequence, allowing us to visually correlate waveforms of adjacent sources. The new locations show vertical containment within individual, targeted sands, suggesting little or no hydraulic communication between the discrete perforation intervals simultaneously treated within an 80-m section. Treatment lengths inferred from event locations are about 200 m greater at the shallow perforation intervals than at the deeper intervals. The highest quality locations indicate fracture zone widths as narrow as 6 m. Similarity of adjacent-source waveforms, along with systematic changes of phase amplitude ratios and polarities, indicate fairly uniform focal mechanisms (fracture plane orientation and sense of slip) over the treatment length. Composite focal mechanisms indicate both left- and right-lateral strike-slip faulting along near-vertical fractures that strike subparallel to maximum horizontal stress (S_{Hmax}). The focal mechanisms and event locations are consistent with activation of the reservoir's prevalent natural fractures, fractures that are isolated within individual sands and trend subparallel to expected hydraulic fracture orientation (S_{Hmax} direction). Shear activation of these fractures indicates a stronger correlation of induced seismicity with low-impedance flow paths than is normally found or assumed during injection stimulation.

INTRODUCTION

The volume of rock stimulated by hydraulic fracturing can be imaged by detecting and locating microearthquakes induced by the injection (Albright and Pearson, 1982). In this paper we apply a high-precision location technique to improve the image resolution of a hydraulic fracture treatment in a tight gas sand reservoir in east Texas. The reservoir is representative of low-permeability gas resources that require hydraulic stimulation for economic production. As a diagnostic, microseismic source locations measure the stimulated volume's orientation, length, and height as well as its growth characteristics, information used to calibrate fracture models, improve treatment design, and guide well placement for optimizing field drainage.

Hydraulic-fracture induced seismicity typically forms an elongated cloud of event locations (e.g., House, 1987; Jones et al., 1995; Warpinski et al., 1995; Phillips et al., 1998). The dominant source mechanism is shear slip, which is induced by elevated pore pressure reducing normal stress along pre-existing fractures (Pearson, 1981). Slip may also occur near the tips of created fractures due to large shear stresses generated by tensile opening (Sneddon, 1946). Since shear slip can be triggered by small pore-pressure increases relative to crack-opening pressure, we expect the microseismic events to extend into the rock, beyond the opened hydraulic-fracture lengths and widths (Evans et al., 1999). The seismic cloud thereby envelops the hydraulic fracture. This interpretation has been supported by stress and focal-mechanism information (Fehler, 1989; Cornet and Yin, 1995; Roff et al., 1996) and inferred from the development of the seismic cloud's length and width (Warpinski et al., 1995; Phillips et al., 1998; Cornet, 2000). By intersecting and extending beyond the created hydraulic fractures, shear-active fractures may form significant components of the fracture-drainage network (Hopkins et al., 1998; Tezuka and Niitsuma, 2000; Evans and Jones, 2001). Moreover, the induced shear slip will result in the mismatching of rough fracture surfaces and create permeability by self-propping of natural fractures (Brown and Bruhn, 1998; Narayan et al., 1998; Warpinski, et al., 1998).

Details on how a treatment interacts with and affects a reservoir's natural fractures cannot be readily gleaned from the seismic cloud. Routine event locations provide blurry images of the fracture system that only outline gross treatment dimensions (Jones and Stewart, 1997; Fehler et al., 2001). It is possible, however, to improve relative source locations and resolve discrete structures by extracting more consistent arrival-time picks through correlation of similar waveforms (Moriya et al., 1994; Phillips et al., 1997; Gaucher et al., 1998; Phillips, 2000; Tezuka

and Niitsuma, 2000; Rowe et al., 2002). This technique also aids in determining focal mechanisms of the induced events (fracture plane orientation and sense of slip) that are difficult to solve with sparse receiver networks. Planar structures resolved by re-location, for example, can provide independent slip-plane orientations to constrain the focal mechanism (e.g., Phillips, 2000). The source coverage can also be expanded by grouping events with similar waveforms and solving for a common mechanism of the event group (composite focal mechanisms, e.g., Rutledge et al., 1998).

Using event re-locations and focal mechanisms, we take a detailed look at the microseismicity from a treatment in the Carthage Cotton Valley gas field (Figure 1). We first give a brief overview of the reservoir geology, operational set up, and initial image results. We then present the high-resolution source re-location technique, followed by our results and interpretation.

STRUCTURAL SETTING

The Carthage Cotton Valley field underlies 1000 km² of Panola County, East Texas (Figure 1) and is within the northern Gulf of Mexico basin, a structural province of gently dipping beds, open, periclinal folds, and normal faults attributed to diapiric movement of salt (Laubach et al., 1989). Gas is produced from multiple, low-permeability sands within an interbedded sequence of sands and shales. Within the immediate study area, the top of the Cotton Valley formation is about 2600 m deep and approximately 325 m thick. Overlying the Cotton Valley is the Travis Peak formation, another thick (~ 450-600 m) interval of productive, tight-gas sands interbedded with mudstones (Dutton, 1987). Present-day stress in the Cotton Valley and Travis Peak is believed to be a normal-faulting regime with minimum horizontal stress (S_{hmin}) oriented north-northwest. This inference is based on local Quaternary faulting (Collins et al., 1980), hydraulic fracture stress tests, borehole breakouts and coring-induced fracture orientations (Holditch et al., 1987; Laubach and Monson, 1988). Predicted hydraulic fracture orientation is vertical, striking east-northeast. Natural fractures and stress-direction indicators in several local boreholes indicate that, within the Travis Peak and Cotton Valley sand intervals, natural fracture populations are dominated by vertical extension fractures, striking subparallel (within 10°) to the contemporary maximum horizontal stress direction (S_{Hmax}) (Laubach, 1988; Laubach and Monson, 1988;

Dutton et al., 1991). Few, if any, natural fractures occur in the intervening shales. Based on the similarity of expected hydraulic fracture trend and natural fracture orientations, Dutton et al. (1991) noted that Cotton Valley hydraulic-fracture treatments would likely access the natural fracture system.

OPERATIONAL SETTING

In May and July, 1997 a consortium of operators and service companies conducted a series of hydraulic fracture imaging tests in the Carthage Cotton Valley gas field (Walker, 1997; Walker et al., 1998a). Six completion treatments in two wells were monitored (three completions per well). The monitor wells and first-treatment well are shown in Figure 2. Both Mayerhofer et al. (2000) and Urbancic and Rutledge (2000) present the treatment dimensions and interpretations of fracture development obtained from the microseismic locations and source parameters. In this paper we present a re-analysis of the seismicity data from the Stage-3 completion interval (Figures 2 and 3).

Two 715-m-long (2350 ft) arrays of 48 three-component geophone stations were fixed to the outside of 2-7/8-inch production tubing and cemented into the monitor wells CGU22-09 and CGU21-09 (Figure 2). We refer to the CGU21-09 array as Array-1, and the CGU22-09 array as Array-2 (Figures 2 and 3). Geophone stations were spaced at 15 m (50 ft) intervals. Signals were amplified 60 dB downhole, with an additional 48 dB of gain applied uphole before digitizing the waveforms at a 1-ms sample interval. Details of the instrumentation design and installation are presented in Walker (1997). Several data channels were lost from stations partly or wholly damaged during installation. In Array-1, only four stations survived with all three components operating, all within the upper third of its length. For the analysis of the Stage-3 data, we used the subset of stations shown in Figure 3, taking advantage of the arrays' long vertical apertures. Several more stations on Array-2 could be used to fill in the receiver set, however, our subset provides an adequate redundancy of phase arrival times to uniquely constrain the Stage-3 source depths.

Stage-3 Treatment and Initial Locations

Stages 2 and 3 in Figure 3 are within the Upper Cotton Valley formation. The well casing

over the 80-m completion interval of Stage-3 was perforated at six discrete intervals ranging from 3 to 6 m (10 to 20 ft) that targeted specific productive sand layers. Walker (1997) describes the stratigraphy in detail. Figure 4 shows the fracture treatment data and a histogram of the microearthquake event count. A viscous crosslink gel was pumped during the main portion of the treatment to entrain high concentrations of sand proppant into formation. Total fluid volume injected was 1253 m^3 (330,919 gallons). During the treatment Withers and Dart (1997) recorded 1122 events. Urbancic and Rutledge (2000) manually picked arrival times for 760 events from which P- and S-phase onsets could be identified. We located 696 of these (Figures 2 and 3) with RMS residuals $< 5 \text{ ms}$ (the root-mean-square of the observed minus computed arrival times for all stations). The median RMS residual was 1.3 ms. The major error axis is oriented horizontal and subparallel to the trend of event locations with a median length of 16 m ($\pm 8 \text{ m}$, Figures 2 and 3). Most of the seismicity defines two distinct depth clusters within the perforated interval. The seismicity also implies some downward growth of the Stage-3 treatment terminating at the upper boundary of the Stage-2 treatment; upward growth is contained (Figure 3).

The event locations are asymmetric about the treatment well with 95% located on the east side, closer to the monitor wells (Figure 2). The distribution is likely due to limited detection range. Figure 5 shows the relative magnitudes versus source-receiver distances, which we computed as normalized RMS log-amplitudes, averaged for the first 10 ms of P- and S-wave arrivals from the lower 5 stations of Array-2 (Figure 3). We corrected the amplitudes for spreading, attenuation (Rutledge, 1998), and radiation pattern determined from composite focal mechanisms (presented below). The lower bounds of the shaded area represents a symmetric detection threshold about the treatment well, limited by the magnitude-distance threshold along the western trend (Figure 5). The events with magnitudes exceeding the symmetric threshold form comparable event populations located symmetrically on each side of the treatment well. Further, 93% of all events east of the treatment well would have been out of detection range had they occurred an equal distance west of the well (Figure 5). Assuming that the small magnitude events were also evenly distributed about the treatment well, we speculate that the fracture lengths could be symmetric. In our re-analysis of the Stage-3 data, we concentrate on the higher-quality data and better-resolved image from events east of the treatment well (Figure 2).

SOURCE LOCATION TECHNIQUE

We determined the locations shown in Figures 2 and 3 using an iterative, least-squares method (e.g., Aki and Richards, 1980, p. 692-695) that has been generalized to include particle-motion data (Phillips et al., 1998), so that misfits of both traveltimes and angular data are minimized. We estimated source-to-receiver azimuths from the principal eigenvector fitting the first 6 ms of horizontal-component, P-wave particle motions (Flinn, 1965). To improve relative locations, we applied P and S station corrections (see Pujol, 1988) based on median traveltime residuals (observed minus predicted values) from initial location runs. This method of determining station corrections approximates those obtained from joint-hypocenter-determination, if, as in our case, many widely distributed events are recorded by several stations (Frohlich, 1979; Pujol, 1988). We estimated arrival-time uncertainties for each station in initial location runs as the standard deviation of the corresponding traveltime residuals. The azimuthal (particle-motion) uncertainties were estimated beforehand from the scatter of data between vertically adjacent stations. In locating the events, we weighted data by the reciprocals of their uncertainties. Table 1 summarizes the traveltime residuals. The estimated location errors reflect the distribution of data types, station-event geometry and the data uncertainties; we did not consider possible uncertainty in the velocity model.

Data available to construct a velocity model included P and S sonic logs and a set of primacord shots fired in the treatment well and recorded on both arrays. A perforation-gun subassembly was used to detonate the primacord, and a geophone in the cablehead provided detonation time. A six-layer model, initially based on the smoothed sonic logs, was calibrated (Rutledge and Urbancic, 1999) using the shots and the best microearthquake data as input to a joint hypocenter-velocity inversion routine (Phillips et al., 1998).

Improving Location Precision Through High-Precision Picking

Using the same algorithms described above, we re-located the microearthquakes with arrival-times obtained by systematic and consistent repicking of events with similar waveforms (e.g., Phillips et al., 1997). Events that occur repeatedly on the same fault plane or along adjacent, similarly-oriented fault planes produce nearly identical waveforms at a receiver station if they

result from the same sense of slip (Poupinet et al., 1984). For comparison, we rotated all waveform data to P (radial), SH and SV components (Figure 6), assuming straight raypaths between events and stations. We then repicked P- and S-arrival times in east-to-west sequences for three depth intervals defined by the initial locations. This allowed us to visually correlate waveforms of adjacent events. We also upsampled the data from a 1-ms to a 0.2-ms sample interval by interpolating using a finite-impulse-response (FIR) filter. Interpolation improved the visual correlation by removing apparent waveform differences caused by the relatively coarse, initial sampling rate (Figure 7). Because the data were properly anti-alias filtered in the field, the FIR-filter interpolation can be considered to be a band-limited signal reconstruction, with initial data sampling representing a data compression; no unsubstantiated information is added in the interpolation process (Vaidyanathan, 1990). Subsample arrival-time precision was obtained from the interpolated data by consistently picking easily identified peaks or troughs within the first half cycle of P- and S-phases (e.g., righthand side of Figure 7). By picking peaks or troughs we avoided the uncertainty of trying to pick phase onsets which varies with signal-to-noise ratio, and by interpolation we reduce uncertainty of identifying the phase maxima and minima due to coarse sampling.

We used easily identified SH phases (e.g., Figure 6) as reference arrivals for displaying waveforms in identical time windows, allowing quick visual correlation. We were often able to obtain reliable SH picks for all 10 receivers of both arrays. New P-wave picks were only made on the lower 5 stations of Array-2 (Figure 3). We did not pick SV because of their poor signal-to-noise ratios (e.g., Figure 6). Repicking the events in spatial sequence revealed a similarity of adjacent-source waveforms over the entire treatment length (Figure 8).

RESULTS OF HIGH-PRECISION PICKING

The original and high-precision locations east of the treatment well are shown in Figures 9 and 10, respectively. The new locations in Figure 10 show a narrower fracture-zone; repicking reduced the standard deviation of locations about a linear fit by more than a factor of four. In depth view, the new locations show five distinct horizontal bands of events within the treatment interval (Figure 10), banding that cannot be seen in the original locations (Figure 9).

Particle-motion-direction data were weighted to one-tenth of the traveltime-data weights to reduce their larger (angular) contribution to location error. The particle-motion data primarily resolved the ambiguity of locations about the plane of mirror symmetry formed by the two monitor wells. As described above, we obtained and applied station corrections to all the events. Afterwards we examined the residuals at each station as a function of location depth and found that the events within each depth cluster had median station residuals variously shifted from zero. These non-zero residuals are most likely due to local, small-scale errors in the velocity model. To improve relative locations further, we incremented station corrections for the distinct depth clusters separately, zeroing their respective median residuals.

On average the new arrival picks have four times less scatter than the original picks (Table 1). The major error axes are horizontal and subparallel to the fracture trend, as in Figures 2 and 3, but with the average length reduced from 16 m to 4 m (± 8 m to ± 2 m). Average relative depth error is slightly less than ± 1 m. The plan-view changes in event location indicate that the initial location errors are underestimated (Figures 9 and 10). Station coverage is very poor in plan view (Figure 2), providing inadequate arrival-time redundancy. As a result, noisy arrival-time data can be over-fitted, giving residuals that underestimate pick errors.

Focal Mechanism Solutions

The similarity of waveforms along the event trend and a change in P-polarities occurring about 270 m east of the treatment well (Figure 8), suggest that a common focal mechanism occurs over the entire length of the fracture system. Waveform character is generally dominated by large-amplitude SH phases (e.g., Figure 6). Proceeding along the treatment length, the sense of P-polarity change near the 270-m distance is correlated with SH polarity. For example, events with negative SH polarity, have P polarities changing from dilational to compressional proceeding eastward across the 270-m distance (e.g., Figure 8, negative SH polarity corresponds to left first-motion at the source, looking at receiver Array-2). Events with positive SH polarity (right first-motion) exhibit the opposite change in P polarity along the treatment. From this simple relationship, we formed two event groups based on SH polarity and computed composite focal mechanisms constrained by the P-wave polarity data alone (using Reasenber and Oppenheimer's

(1985) routine). SH first motions for 90% of the events are to the left, the remaining are to the right. The solutions for both event groups uniquely converged to strike-slip mechanisms consistent with their SH motions and with only 4 to 5% discrepant P-wave first motions (Figure 11). The ratios of the SH- to P-amplitudes (SH/P) for both data groups are consistent with the first-motion-constrained, strike-slip solutions (Figure 12). The same strike-slip solutions were determined for event subsets using a combination of P- and SH-polarities and the amplitude ratios of SH/P-, SV/SH- and SV/P as input to Snoke et al.'s (1984) focal-mechanism routine.

The compositing of the P-wave first-motion data is justified by: 1) the similarity of adjacent-source waveforms throughout the data set (Figure 8); 2) the consistency of both SH first motions and amplitude ratios with the P-polarity-constrained solutions (Figure 12); and 3) the agreement between strike of nodal planes with the event-location trend (Figure 11). The dips of the nodal planes closest to the event trends are poorly constrained by the P-polarities alone (Table 2) due to the limited focal sphere coverage (Figure 11). However, SV amplitudes are generally very low (e.g., Figure 6), and the distribution of SV/SH amplitudes over the treatment length restrict the slip planes to near vertical.

FEATURES AND INTERPRETATION

Focal Mechanisms

As summarized above, the prevalent natural-fracture orientation expected within the reservoir is vertical and striking within 10° of S_{Hmax} . We interpret the focal mechanism groups to represent slip induced on these pre-existing fractures, with the sense of slip determined by the fracture plane's strike relative to S_{Hmax} . The seismic trend in Figure 10 is N80°E, consistent with independent measurements of S_{Hmax} direction (Laubach and Monson, 1988). Both fault-plane solutions show a nodal plane within 10° of the seismic trend (Figure 11). Although the fault-plane strikes are not statistically distinct (Table 2), they show the correct sense of rotation required to change from left-lateral to right-lateral slip. This relative sense of strike is independently supported by the SH/P amplitude ratios. Mean SH/P ratios for the right-lateral solution (Figure 12, bottom) are shifted about 5° to the right with respect to the left-lateral solution (Figure 12, top), corresponding to a counter-clockwise rotation of the fault-plane strike. Stress heterogeneities

along the treatment length could also result in local slip reversal for fractures striking close to S_{Hmax} . However, there is some spatial separation between the two focal mechanism groups that suggest distinct fracture populations. The majority of right-lateral events are along the southern margins of the event trend. There is no temporal distinction; the proportions of the two event groups are fairly constant during pumping and shut-in periods. A predominance of fractures striking slightly clockwise of S_{Hmax} may explain the more frequent occurrence of left-lateral slip.

Depth Distribution of Microseismicity

Figure 13 shows a histogram of the microearthquake depth distribution along with the treatment well's proppant radioactive (RA) tracer log and perforation sub-intervals. Both proppant and fluid were tagged to give a qualitative diagnostic of the treatment behavior near the well. The RA tracer log shows that the propped fracture height was reasonably well contained with the highest concentrations of sand staying close to the perforated depth intervals. We shifted two event subgroups to align the microseismicity with the RA tracer log and perforation intervals; events above 2650 m were shifted down 4 m and events below 2680 m were shifted up 2 m (Figure 13). The absolute depths of the clusters can be reasonably shifted up or down a few meters, due to velocity uncertainties suggested by the magnitude of station corrections (~1 ms on average). Our shifts to enhance the correlation are also reasonable based on correlations of microseismicity with fracture conductivity and fluid flow at various other sites (e.g., Dreesen et al., 1987; Branagan et al., 1997; Jupe et al., 1998; Rutledge et al., 1998; Tezuka and Niitsuma, 2000; Evans and Jones, 2001).

The containment of seismicity within the target sands suggests that the discrete sand intervals are hydraulically isolated (Figures 10 and 13). This containment is also consistent with activating the reservoir's prevalent natural fractures, which are confined within individual sands and largely absent in the intervening shales (Dutton et al., 1991). Only a few events occur within the top perforations interval (labeled **A** in Figure 13), though the RA tracer log shows high concentrations of proppant near the treatment well. The RA tracer log also detected low-levels of the tagged fluid beneath the Stage-3 perforated section, suggesting channel flow behind casing. Since the seismicity above indicates good intra-perf containment far into formation, we conclude

that the banded seismicity below the Stage-3 treatment interval is likely to have resulted from flow behind casing reaching more permeable horizons below.

Treatment Length and Width Development

Figure 14 illustrates the length development for the two most populous depth clusters during the main portion of the treatment. The initial, rapidly attained lengths out to about 150 to 200 m correspond to the lengths developed during the earlier, treated-water injections shown in Figure 4. The space-time event sequences of Figure 14 show envelopes of activity over large lengths of the treatment. Often the envelope edges form clear linear trends, defined by similar magnitude events, suggesting systematic migration of shear dislocations. Although less clear, such linear trends can also be seen within the envelope of active treatment length. The seismicity migrates both away from and towards the treatment well. The positions of individual events oscillates over the envelope length, sometimes jumping from one edge to the other. In general, larger magnitude events occur closer to the treatment well, perhaps simply due to higher pore pressure (Figure 14). As the injection progresses, an aseismic zone develops, generally expanding away from the treatment well and attaining lengths of about 1/3 to 1/2 of total seismic length. A comparable zone developed during the Stage-2 treatment (see Figure 4c of Urbancic et al., 1999). In both cases the aseismic zone developed soon after injection of the crosslink gel was started. The aseismic zone may be due to the complete relaxation of shear stress and a possible indicator of fracture length being maintained open.

Expanded displays of the best locations (smallest RMS residuals) within these same two depth intervals, show fracture zones width as narrow as 6 m (Figures 15 and 16). A coarse time sequence illustrated by the type of event-symbol filling shows a general migration of events normal to the trend for the deeper subcluster, suggesting that the fracture zone widens as the treatment progresses (Figure 15). The widening may be caused by or at least exaggerated by temporal changes in velocities over portions of the travel paths affected by the injection. The shallower subcluster does not show the systematic temporal widening (Figure 16). Instead, late in the treatment, the shallow zone attains about 200 m more length than the deep interval (Figures 16 and 15, respectively, also seen in Figure 10). The event trend also offsets about 6 m to the south at

about 230 to 250 m east of the treatment well (Figure 16), possibly caused by a crosscutting structure. The detailed event sequence in length also suggest a breakdown of some barrier associated with the trend offset. Prior to hour 11.5 the event density is high near the fracture terminus at about 230 m (Figure 14, interval C). Following the introduction of proppant flow, seismicity extends eastward at a higher rate (Figure 14) past the trend offset (Figure 16). The proppant may have acted as a fluid diverter, increasing the net pressure over the shallow intervals, by preferentially screening out or impeding flow at the deep perforations.

The general event-sequence patterns, active at once over large lengths of the treatment (Figure 14) and possibly developing width (Figure 15), suggest that multiple, subparallel fractures are being pressurized by leak off (fluid flow and pressure dissipation through the matrix or interconnecting fractures along the treatment length). Studies from numerous other sites indicate that multiple-fracture geometries are commonly created or pressurized during hydraulic fracturing (Mahrer, 1999), including some coring and mineback tests that have revealed total fracture-zone widths and trend-offsets comparable to that resolved in Figures 15 and 16 (e.g., Warpinski and Teufel, 1987; Hopkins et al., 1998).

DISCUSSION

The initial and re-located seismicity images are very different from predictions of the treatment geometry. Poor vertical containment and short fracture length was expected based on fairly uniform stress (S_{hmin}) and mechanical-property profiles within the Upper Cotton Valley (McCain et al., 1993; Mayerhofer et al., 2000). Subsequent model calibration allowed a reasonable match with the net pressure data and initial event locations (Mayerhofer et al., 2000). The models treat the fracture growth as a continuous process within the whole perforated section, whereas the new event locations indicate that multiple discrete zones were activated, suggesting that the targeted sands were hydraulically isolated. It is possible that hydraulic fractures propagated through the intervening shales, with the shales deforming aseismically. An interesting analogy to this from natural seismicity may be sections of the San Andreas fault that slide largely aseismically, but are populated by small earthquakes that occur, as in our case, along horizontal bands parallel to the direction of slip (Rubin et al., 1999). Nonetheless, we consider hydraulic

isolation to be a reasonable interpretation based on the zones of fluid flow correlating with event locations (Figure 13) and the seismicity's consistency with activating a fracture system that is optimally-oriented for flow and already contained within the target sand intervals.

Patterns of S- to P-wave energy ratios (E_s/E_p) were previously interpreted as an indicator of a non-shear or volumetric component of failure systematically varying along the Cotton Valley treatment lengths (Urbancic and Zinno, 1998; Rutledge and Urbancic, 1999; Mayerhofer et al., 2000). The same data, displayed as amplitude ratios in Figure 12, can instead be attributed to the radiation patterns of two similar, double-couple, shear mechanisms occurring uniformly over the treatment length. The P- and SH-polarity changes, waveform similarity, new locations and natural fracture geometry all support this simpler interpretation. Further, for a treatment in well 21-09 at the same depth (Figure 2), we found identical patterns of polarities and amplitude ratios fixed with respect to the common monitor well (Array-2, see Figure 3 of Rutledge and Phillips, 2002). Using a Coulomb failure criteria, the pore pressure required to induce horizontal slip along fractures subparallel to S_{Hmax} will be relatively high. Therefore, the uniform focal mechanisms imply a lack of natural fractures along the treatment length that would be more favorably oriented for shear failure (fractures with higher resolved shear stress, lower critical pore pressure).

Pressurizing the existing fractures may be the primary process of enhancing permeability and fracture network conductivity over most of the length attained, rather than creating fresh hydraulic fractures. The high pore pressure required for shear slip should be approaching fracture opening pressures. Hence, incremental pressure increases are likely to extend the shear-active fractures as hydraulic fractures, improving the chances of connecting subparallel fracture strands. Although seismically we primarily observe shear slip, the patterns of event sequences in Figure 14 are consistent with extending existing fractures, with the shear events being the precursors to opening and incremental growth. Shear stress transferred by the strike-slip displacements would load the fracture zone ahead and behind the rupture perimeters. This would further promote strike-slip failure, resulting in the repetitive, linear migrations. If the trailing aseismic zone represents the fracture length being maintained open, as pressure further increases, then it may in turn indicate the lengths over which proppant would most easily be carried into formation.

High critical pore pressure also implies low effective-normal-stress conditions for slip, a condition favoring permeability creation through shear dilation. In general, slip occurring under lower normal stress will allow higher dilation angle and reduce the shearing-off of steeper, short-wavelength asperities, resulting in more effective, permanent dilation than shearing under higher normal stress (see Evans et al., (1999) and references therein). Conditions favoring effective shear dilation further supports the self-propping mechanisms suggested by other investigators for the success of Cotton Valley treatments using water and very low proppant concentrations (Mayerhofer et al., 1997; Mayerhofer and Meehan, 1998).

Why Strike-Slip Faulting?

The prevalence of strike-slip faulting is surprising. Using Zoback and Healy's (1984) criteria, effective stress ratio of overburden (S_V) and S_{hmin} at hydrostatic pore pressure implies a critically stressed condition for normal faulting at reservoir depths. Local neotectonic activity has occurred primarily as normal faulting (Collins et al., 1980; Pennington and Carlson, 1984). It is therefore unlikely that S_{Hmax} exceeds S_V . Since the natural fractures show both dip and strike angles subparallel to S_V and S_{Hmax} , respectively, the propensity for dip-slip motion should be greater or comparable to the propensity for strike-slip motion. Dutton et al. (1991) noted that fracture curvature commonly results in opposed dip directions along vertical fracture traces within the Cotton Valley formation; this could inhibit vertical slip. As an alternative or additional mechanism to inhibit vertical slip, we speculate that for planar, near-vertical fractures through horizontal beds, the shear strength across the rock fabric (dip-slip direction) may be significantly greater than along the lamination direction (strike-slip direction). Finally, elevating the pore pressure throughout the cylindrical rock volumes, inferred from the horizontal microearthquake clusters, will result in the poroelastic effect of increasing stress primarily along the volume's major axis (S_{Hmax} direction), thus promoting strike-slip faulting along the treatment length (e.g., Segall and Fitzgerald, 1998).

CONCLUSIONS

We have re-located the microearthquake events for an Upper Cotton Valley hydraulic fracture stimulation using high-precision arrival-time data obtained from the waveforms.

Compared to the original locations, the new arrival-time data result in 4-fold improvement in location precision. The new locations are vertically contained within the individual, targeted sands, suggesting little or no hydraulic communication between discrete perforation intervals over an 80-m stimulated section. Treatment lengths at the shallow perforation intervals are about 200 m greater than at the deeper intervals. The event-sequence patterns suggest that the length differences may be due to proppant preferentially impeding flow at the deeper intervals. The highest quality locations indicate that fracture zone widths were as narrow as 6 m. Seismicity that occurred below the injection depths is likely to have resulted from fluid flow behind casing and then out into permeable horizons below.

The similarity of waveforms from nearby events seen throughout the data set, along with systematic changes of phase amplitude ratios and first-motion polarities, indicate two fairly uniform focal mechanisms occurring over the entire fracture length. Composite focal mechanisms indicate both left- and right-lateral strike-slip faulting along near-vertical fractures that strike subparallel to S_{Hmax} .

The focal mechanisms and event locations are consistent with activation of the reservoir's known natural fracture system, a system that is dominated by vertical fractures isolated within individual sands and that trend subparallel to expected the hydraulic fracture orientation. Activation of these fractures indicates a stronger correlation of seismicity with low-impedance flow paths than is normally found during injection stimulation. Since the seismically-active fractures are not optimally oriented for shear slip, critical pore pressures should be high, probably approaching crack-opening pressures. Incremental pore-pressure increases are likely to subsequently extend the shear-active fractures as hydraulic fractures, improving the chances of connecting multiple, subparallel fracture strands. High critical pore pressure also implies low effective-normal-stress conditions for slip, a condition that should favor more effective permeability creation via shear dilation.

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Hydraulic Stimulation of Natural Fractures

Station	Original Locations		High-Precision Locations	
	P	S	P	S
2-38	0.8	1.0	0.2	0.2
2-33	0.8	0.9	0.2	0.2
2-30	0.9	1.3	0.2	0.2
2-24	1.0	0.9	0.3	0.3
2-20	1.0	0.7	0.3	0.2
2-12	1.4	0.8	*	0.1
2-08	1.2	0.9	*	0.2
2-04	2.8	1.0	*	0.3
1-34	*	1.3	*	0.2
1-19	*	0.9	*	0.8

Table 1: Standard deviation of traveltimes residuals (ms) for the original locations (Figure 9) and the high-precision pick locations (Figure 10). Station locations are shown in Figure 3. The * symbols indicate data not used or not obtained.

Composite Solutions	Observations	Discrepant First Motions	Strike	Dip	Rake
Left Lateral	1000	49	N80°E $\pm 10^\circ$	85° $\pm 40^\circ$	0° $\pm 10^\circ$
Right Lateral	307	12	N70°E $\pm 3^\circ$	80° $\pm 40^\circ$	180° $\pm 10^\circ$

Table 2: Summary of P-wave fault plane solutions shown in Figure 11 with uncertainties for the nodal planes nearest to the event-location trend. Rake of 0° = left lateral displacement, 90° = reverse (thrust), $\pm 180^\circ$ = right lateral, -90° = normal.

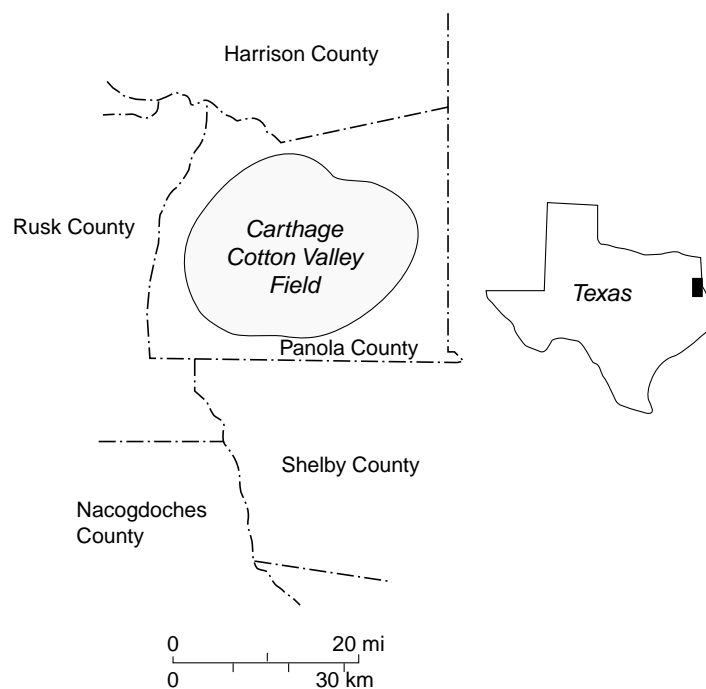


Fig. 1. Location of Carthage Cotton Valley gas field.

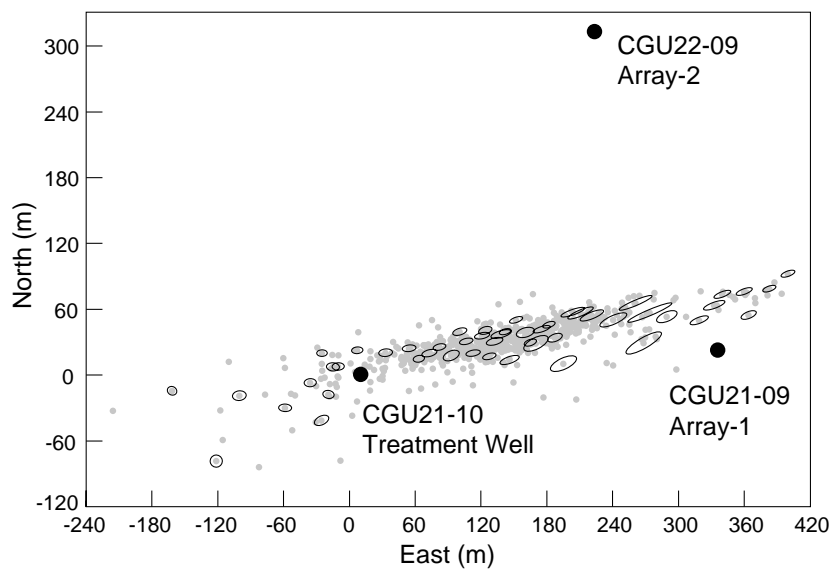


Fig. 2. Treatment, monitor wells and the initial Stage 3 event locations. Some representative error ellipsoid projections are also shown. Datum for all maps herein is the Kelly bushing of CGU21-10 at 119 m above sea level.

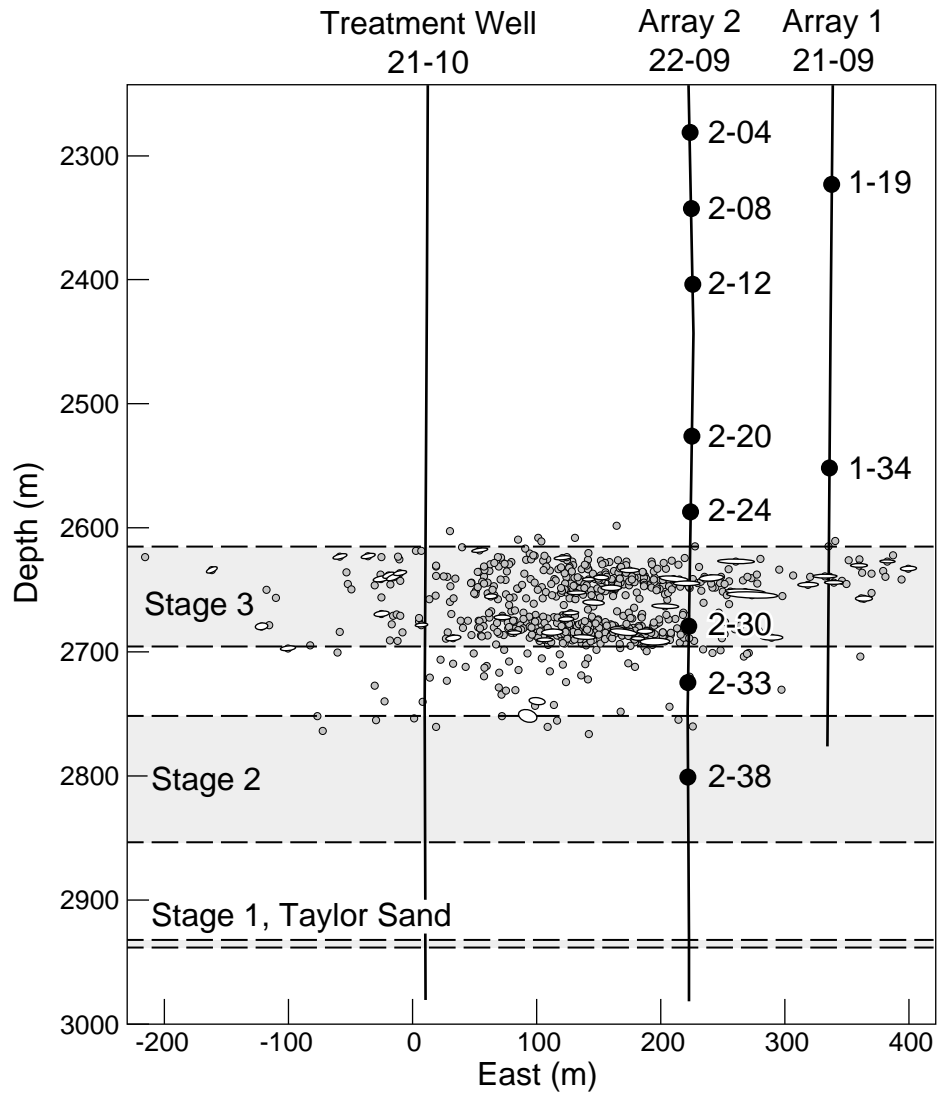


Fig. 3. Depth view of treatment and monitor wells. Three hydraulic fracture completions stages were conducted in the treatment well 21-10. The Stage-3 event locations are shown (same as Figure 2) along with the geophone stations used for determining the locations. Representative error ellipsoid projections are shown.

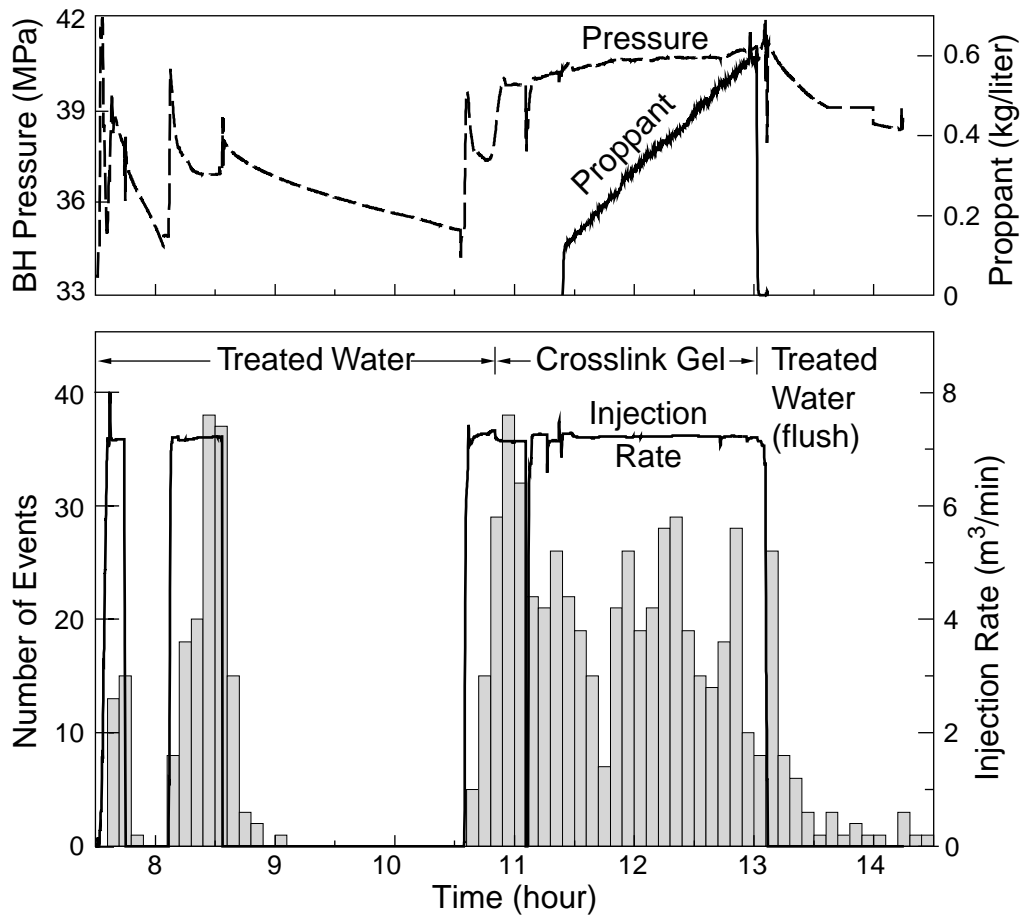


Fig. 4. The Stage-3 hydraulic fracture treatment data and histogram of the induced microseismic events. BH Pressure is the measured bottom-hole pressure.

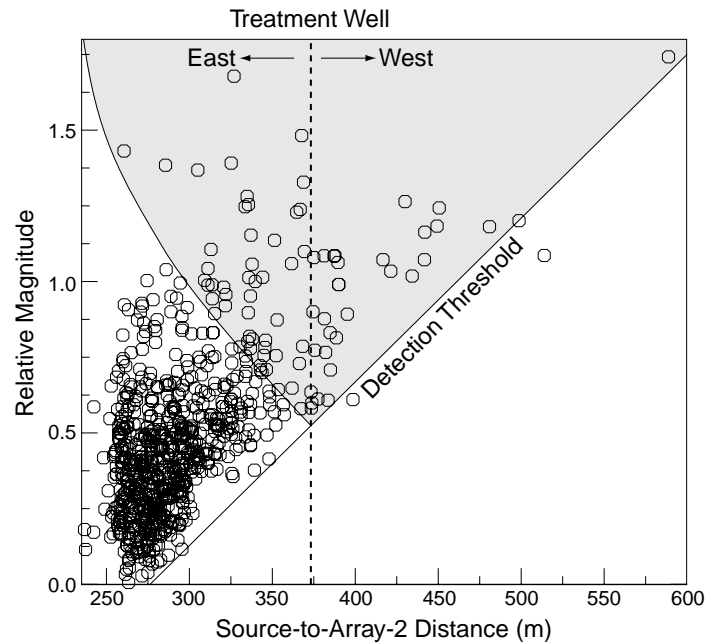


Fig. 5. Relative event magnitudes versus source-receiver distance. The sloping line represents the approximate event detection threshold at Array-2; most events falling below the line would not be detected with signal strength sufficient to be located. The vertical dashed line is at the horizontal distance between the Array-2 well and the treatment well. The curve extending up to the left was determined by obtaining detection thresholds from the sloping line for distances between Array-2 and trial source locations incremented along the western trend of the treatment. These magnitude thresholds were then plotted versus the distance between Array-2 and the symmetric source location, flipped 180° (eastward) about the treatment well.

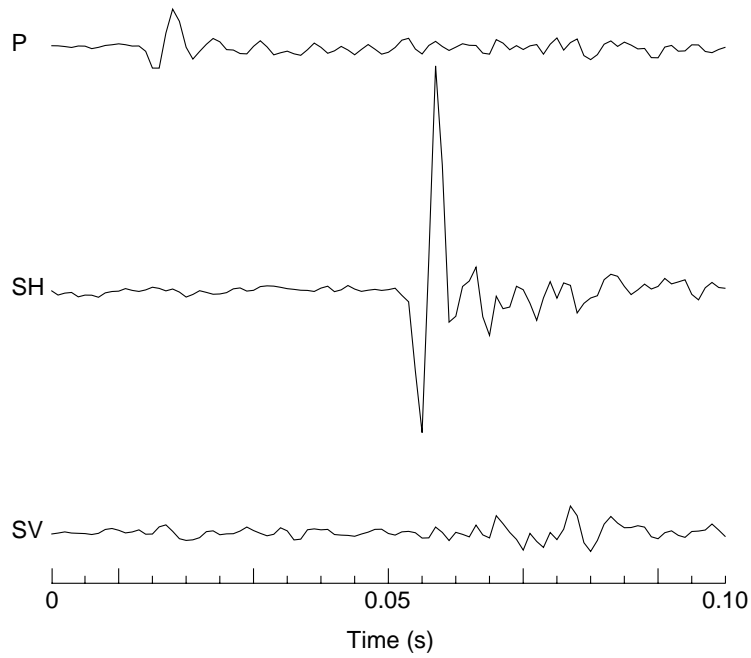


Fig. 6. An example of a high-quality microearthquake waveform recorded on station 2-24. All traces are plotted at the same relative amplitude scale.

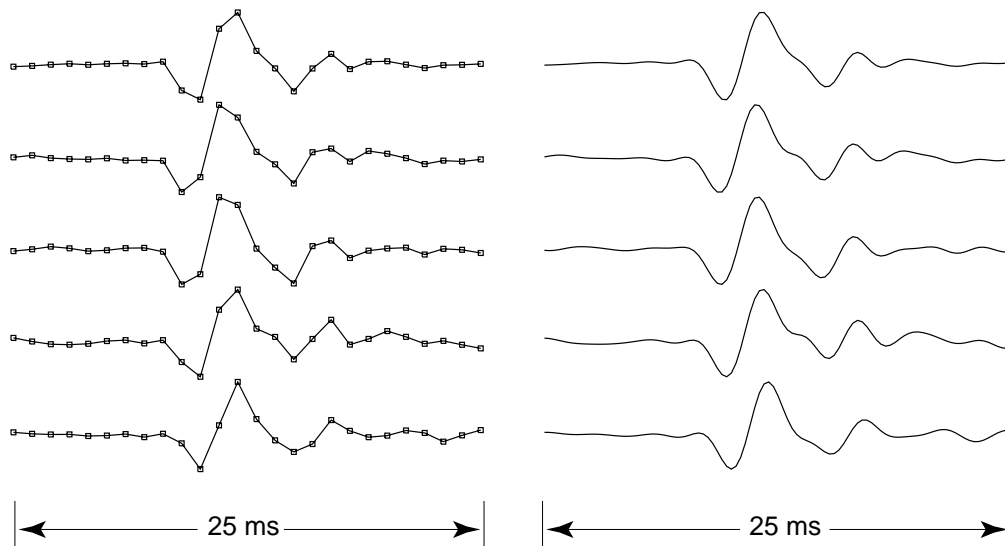


Fig. 7. An example of five similar P-waves from station 2-38. The original data sampled at a 1-ms sample interval (left), and the same waveforms after upsampling 5-fold by spectral interpolation using a FIR filter (right). Each trace is scaled to its maximum amplitude.

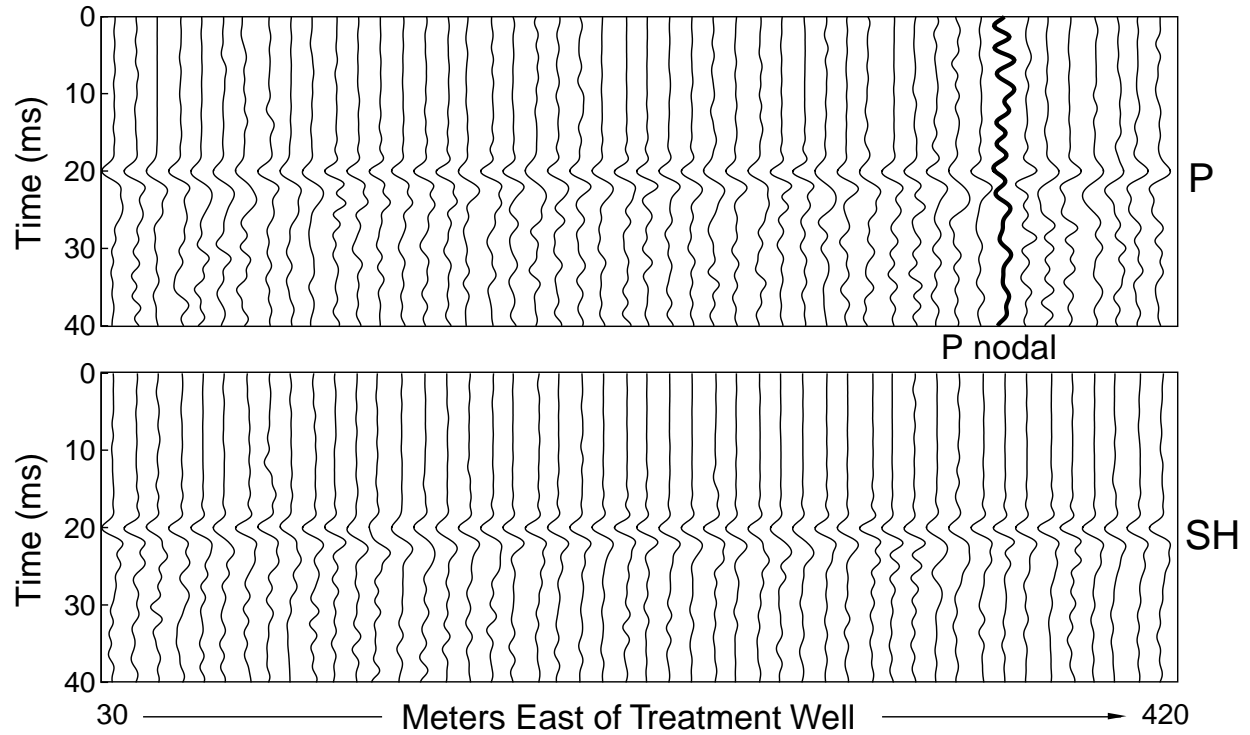


Fig. 8. P and SH arrivals for 50 high-quality (larger magnitudes) microearthquakes with left SH first motions. The event locations are sorted east to west along the treatment, spaced at a mean horizontal distance of 8 m. P arrivals are from station 2-33 and SH arrivals are from station 2-38 (Figure 3). Each trace is scaled to its maximum amplitude and is windowed to align the arrival-time pick at 20 ms. The P-nodal trace (bold) is from an event located 260 m east of the treatment well.

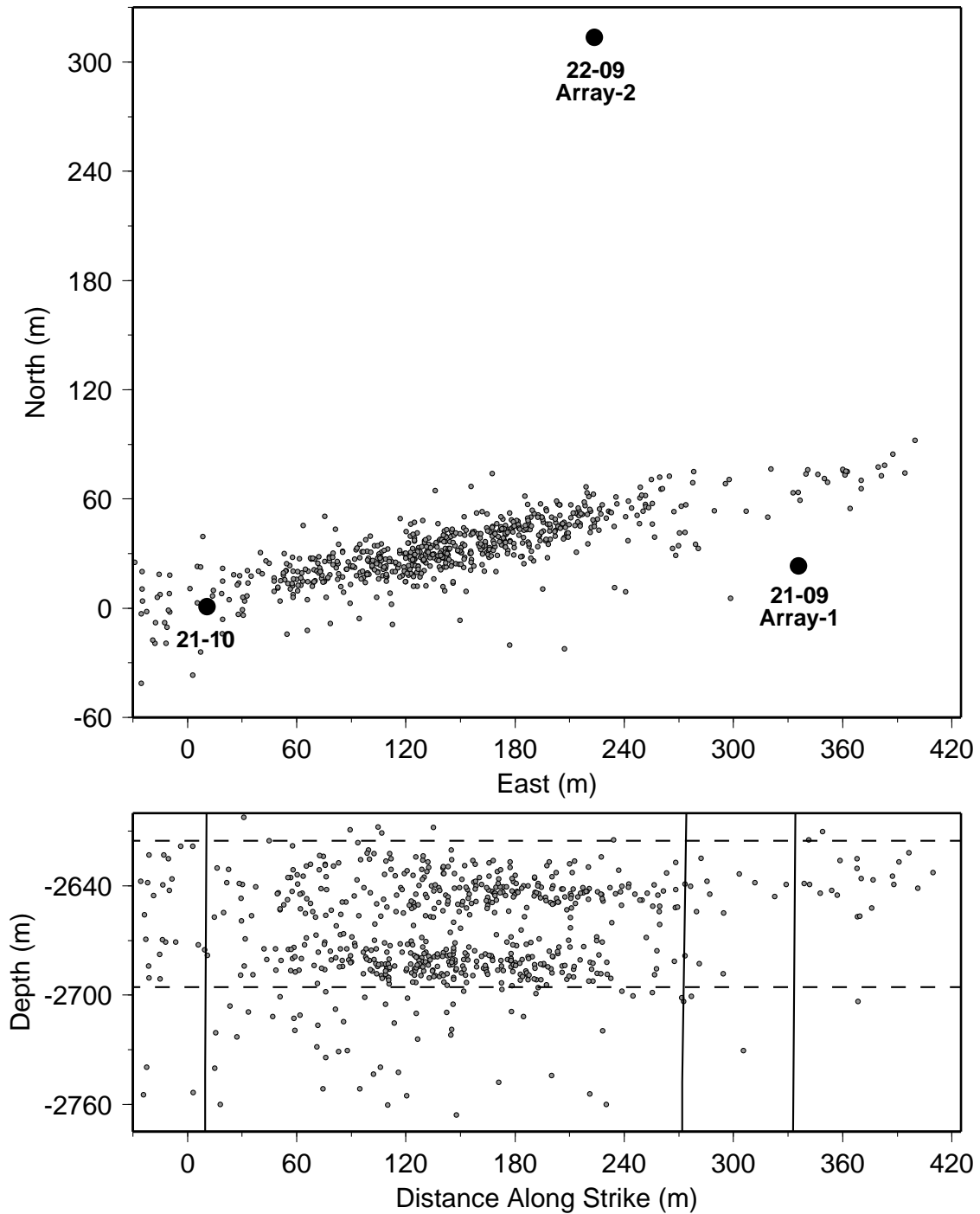


Fig. 9. Original Stage-3 microearthquake locations. Same locations as Figures 2 and 3, but only the events near and east of the treatment well are displayed. The dashed lines mark the Stage-3 injection interval.

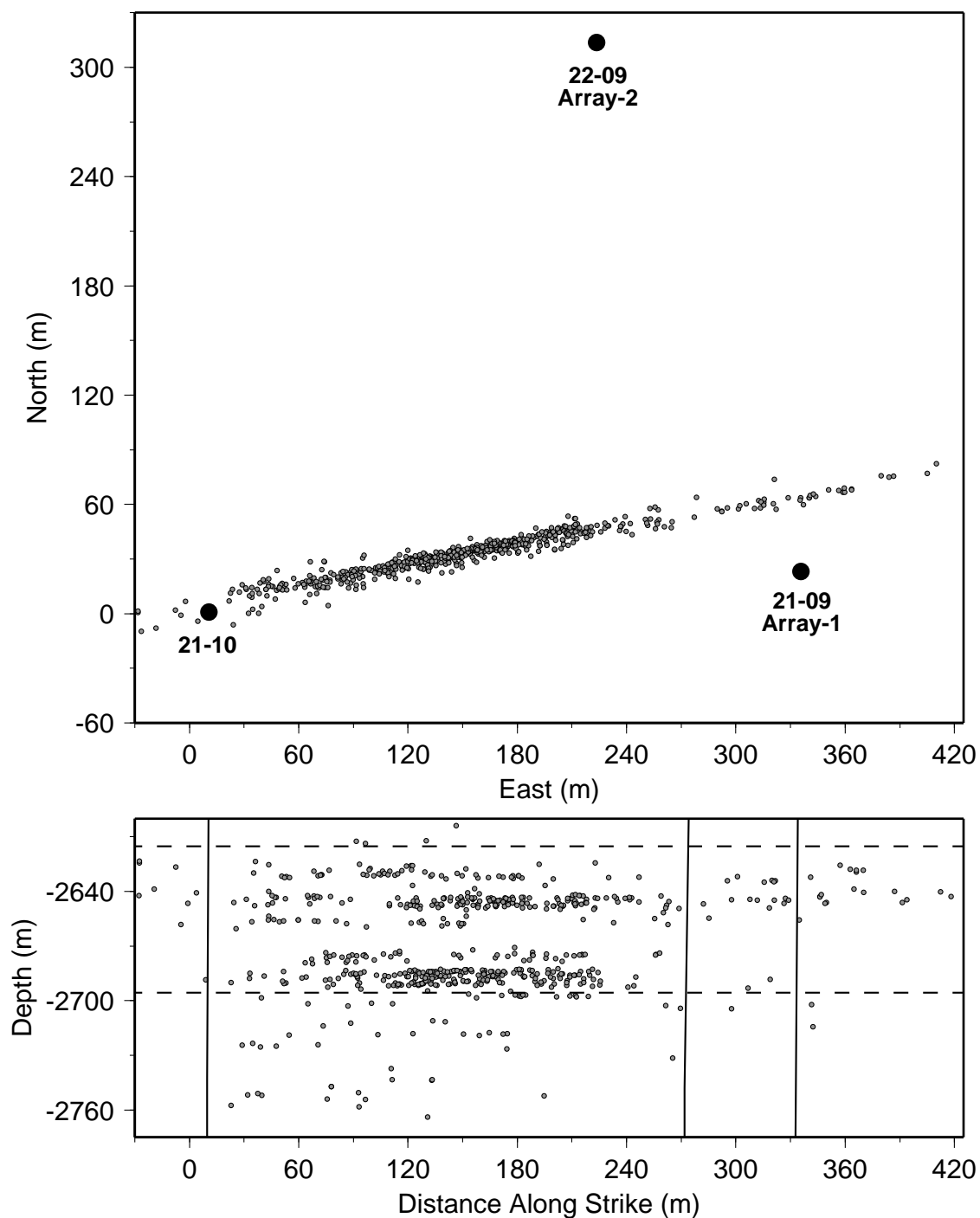


Fig. 10. Same as Figure 9 after obtaining higher-precision arrival-time data.

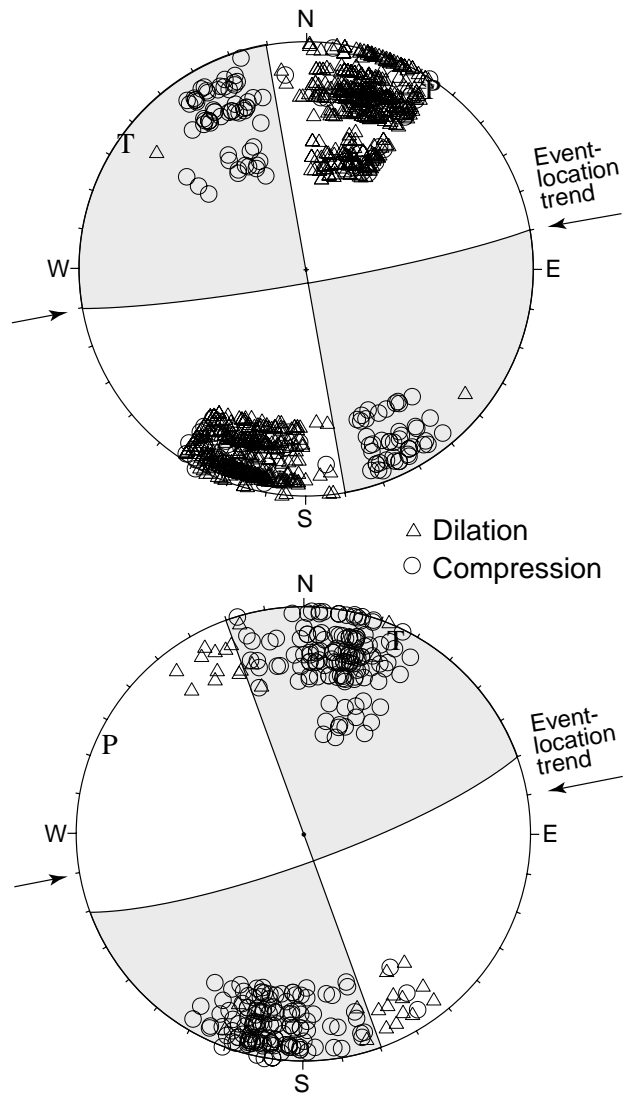


Fig. 11. Composite focal mechanisms using the P-wave first-motion data from all eight stations of Array-2. The compressive quadrants are shaded. The solution for the events with SH first motions to the left is at the top; the lower solution is for events with SH first motions to the right. Input to the focal-mechanism routine was limited to 1000 P-wave first motions. A data-use criteria based on signal-to-noise ratios results in the data gap spanning the nodal plane trending close to N-S (top). All data for the smaller, second group were used (307 first motions, bottom).

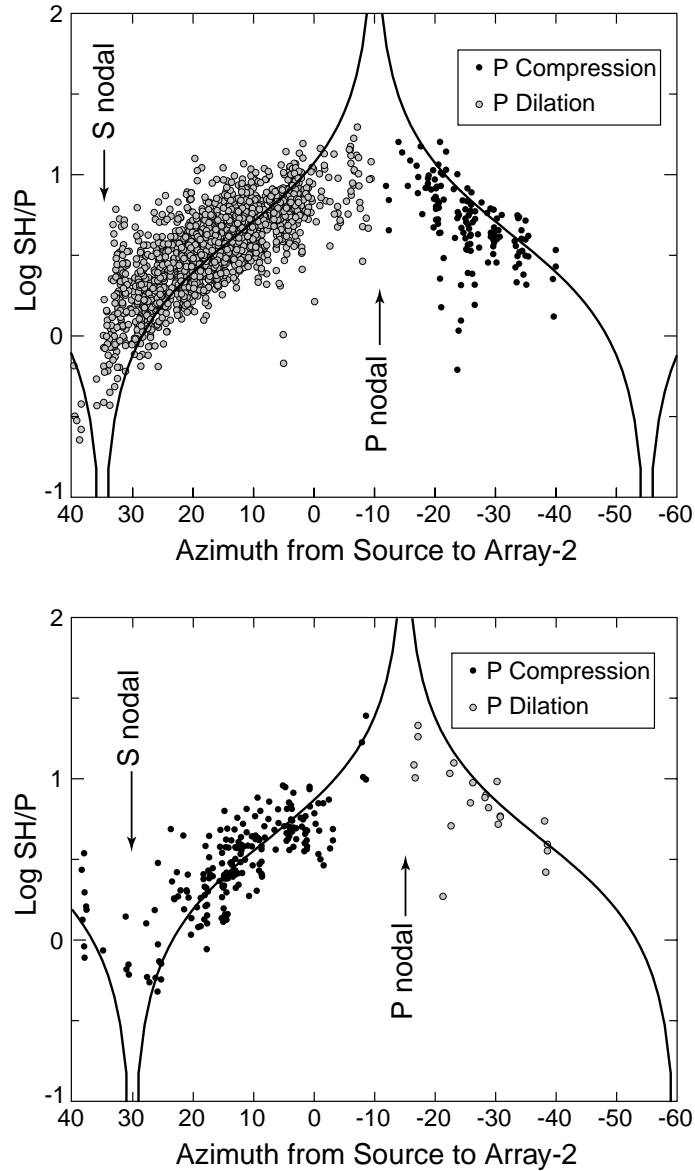


Fig. 12. SH/P amplitude ratios as a function of the azimuth from event to station. The plots correspond to the top and bottom focal mechanisms of Figure 11. Data are from the 5 lower stations of Array-2 (Figure 3). All data with P and SH polarities consistent with the focal mechanisms of Figure 11 are shown (95% of all events). The curves are the theoretical SH/P amplitude ratios for a vertical, strike-slip fault striking N80°E (top) and N75°E (bottom) at horizontal take-off angle (Aki and Richards, 1980). P-polarities are also distinguished. The treatment well is near the SH-nodal azimuth with respect to Array-2.

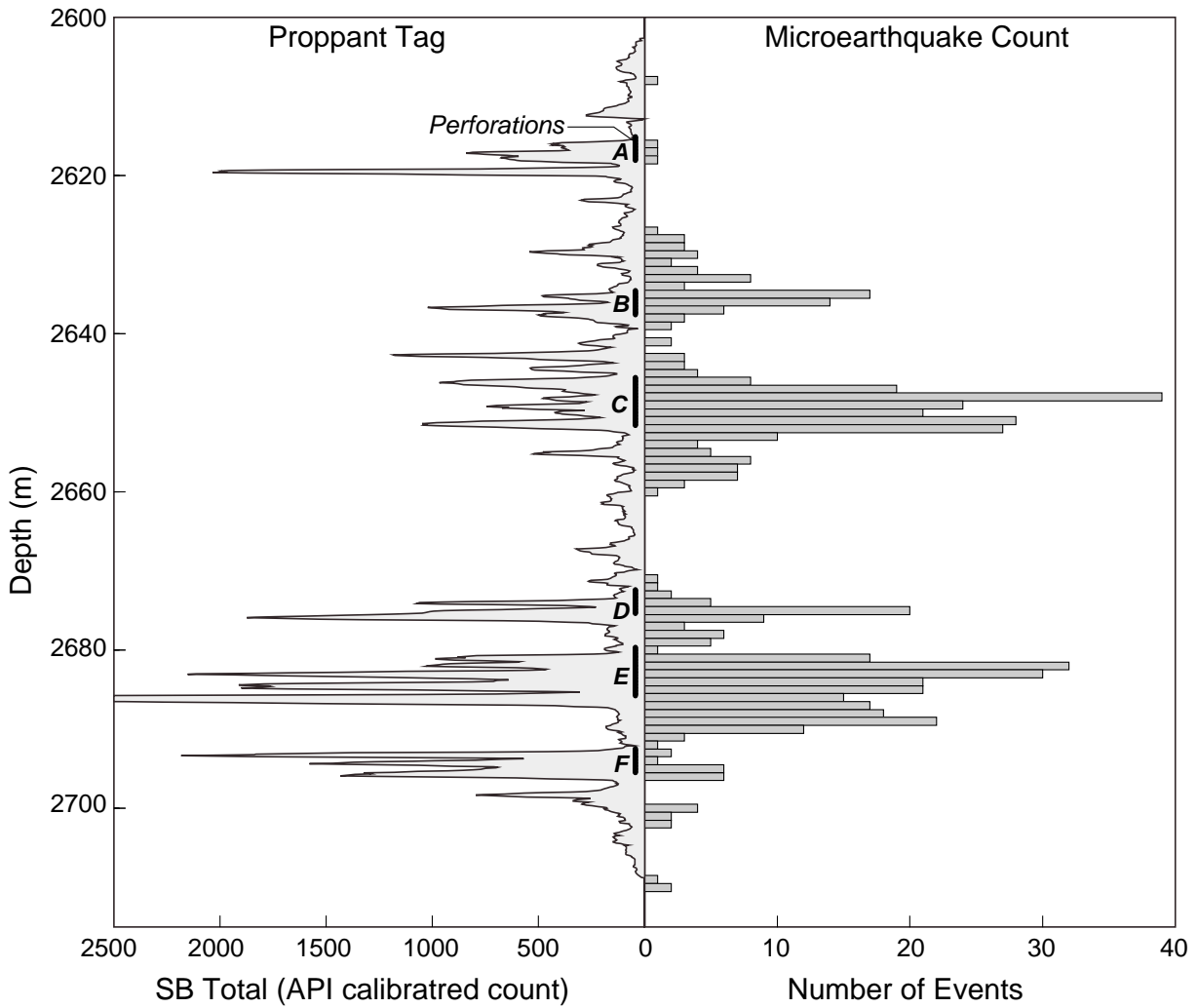


Fig. 13. The depth distribution of microearthquakes within the Stage-3 treatment interval of Figure 10 compared to the radioactive (RA) proppant tracer log. The dark vertical lines labeled **A** through **F** mark the Stage-3 perforation zones of the treatment well 21-10. The RA proppant tag was antimony (SB).

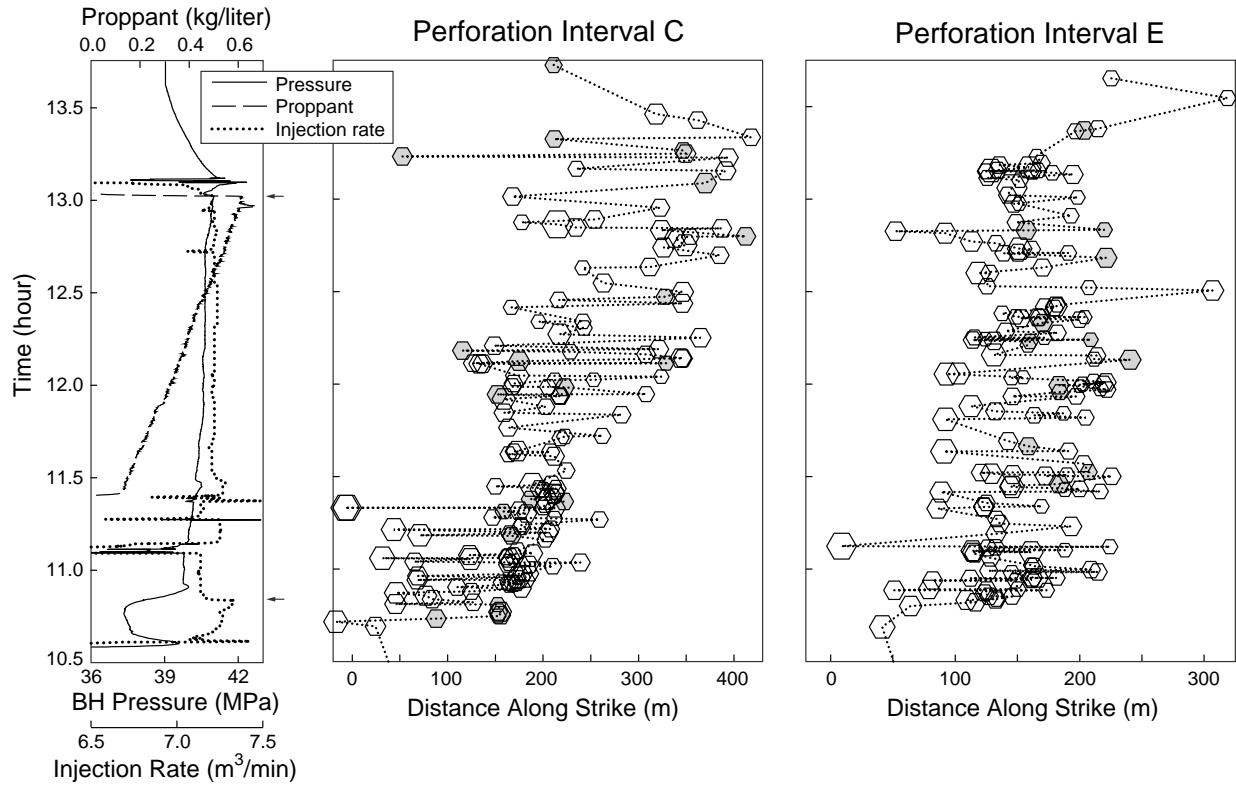


Fig. 14. Fracture growth for the two most populous seismicity clusters associated with perforation intervals **C** and **E** of Figure 13. Symbol sizes are proportional to magnitudes (log-amplitudes). Open and gray symbols distinguish events fitting the left-lateral and right-lateral strike-slip focal mechanisms, respectively. The two arrows mark the interval when the crosslink gel was being injected. Distance along strike represents the eastern wing of the seismicity with the treatment well at zero. Note that the distance scales differ for the two perforation intervals.

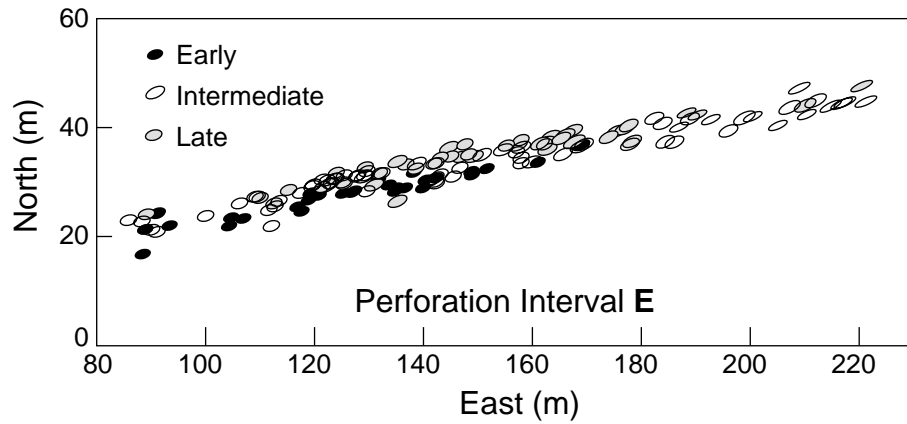


Fig. 15. Detailed map view of the subcluster associated with perforation interval **E** of Figure 13. Only events with RMS residuals ≤ 0.35 ms are displayed. Locations are represented by the projections of the error ellipsoids. The symbol fill represent a coarse time division in the treatment schedule.

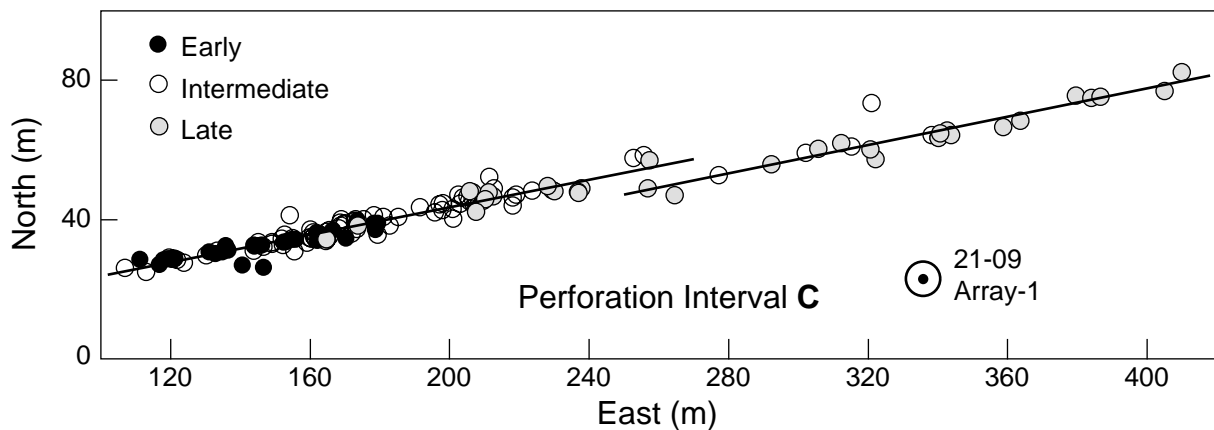


Fig. 16. Detailed map view of the subcluster associated with perforation interval **C** of Figure 13. Only events with RMS residuals ≤ 0.35 ms are displayed. The symbol fill represents the same time sequence as Figure 15. The parallel lines shown on each side of the trend offset near 250 m east are best fit linear regressions for events < 250 m and > 250 m east.